2018 MECHANICAL INTEGRITY AND RESERVOIR TESTING
CLASS I HAZARDOUS DEEPWELLS
Well #1-12; UIC Permit: MI-163-1W-C010
Well #2-12; UIC Permit: MI-163-1W-C011

Environmental Geo-Technologies, LLC
Romulus, Michigan

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1.0 INTRODUCTION

All Class I Waste Disposal Wells must demonstrate mechanical integrity as required by the United States Environmental Protection Agency (USEPA) under the Underground Injection Control (UIC) Program and the Michigan Department of Environmental Quality (MDEQ) Mineral Well Act. The mechanical integrity tests (MITs) conducted July 17 through July 18, 2018 at the Environmental Geo-Technologies, LLC (EGT) Romulus, Michigan facility (Well No. 1-12) demonstrated that "there is no significant leak in the casing, tubing or packer", that no evidence of flow exists behind pipe at the base of the casing strings, and that injection zone pressures have not changed sufficiently from previous testing to warrant further investigation.

This report summarizes the successful MIT activities performed at the Environmental Geo-Technologies, LLC (EGT) Romulus, Michigan facility. The work was performed as a condition of the EGT UIC permits issued by the USEPA and MDEQ. All annual MIT requirements for Well No. 1-12 were satisfied as a result of the work performed. Annual Part I requirements for Well No. 2-12 were satisfied as a result of the work performed. Under contract, Petrotek Engineering Corporation developed the MIT procedures, provided field supervision, provided pressure transient test and logging analysis and prepared the final report documenting the MIT fieldwork on the Class I hazardous injection well located at the Romulus facility.

The test procedures were submitted to the USEPA Region 5 office and the MDEQ field inspector prior to field activities. In addition, field inspectors were notified by phone of the scheduled MIT fieldwork to allow regulatory agency witnessing of the tests. Mr. Jack Lanigan of the MDEQ was present to witness this testing. Approvals were received from regulatory agency staff prior to commencement of activities.

The MIT activities consisted of an annulus pressure test on both wells at the site along with injection falloff test, static temperature survey, and a radioactive tracer survey (RTS) on Well No. 1-12. Well No. 1-12 satisfactorily demonstrated mechanical integrity pursuant to the EGT Underground Injection Control (UIC) permit, applicable guidelines and regulations. Well No. 1-12 wellbore and reservoir properties were confirmed as similar to those determined from analysis of the previous testing conducted in the well.

It is noted that a successful APT was performed on Well No. 2-12, but during field operations logging tools were not able to be run to the bottom of the well. As discussed by EGT with EPA and MDEQ, well rehabilitation plans are currently underway which are intended to allow additional mechanical integrity testing to be conducted on the well.

2.0 MECHANICAL INTEGRITY TESTING

The year 2018 MIT activities on the EGT waste injection wells were supervised by Rich Schildhouse of Petrotek. The MIT activities occurred July 17 through July 18, 2018. The procedures followed in the tests were approved in advance by EPA and MDEQ representatives and all tests were witnessed by Mr. Jack Lanigan of MDEQ. Appendix 1 presents approvals and test procedures. Figure 1 and 1a present wellbore diagrams illustrating the configuration of the wells during testing activities. Note that no changes to the subsurface wellbore configuration were made to the wells at the time of testing during 2018 or since MIT activities were last completed in 2017.

Part I: Internal Mechanical Integrity

Well No. 1-12

On July 17, 2018 the annulus of Well No. 1-12 was pressured up to 970.0 psi. A calibrated digital pressure gauge (Rosemount 2,000 psi, SN-10000096) supplied by EGT was installed on the annulus at the wellhead. After the well was isolated from the surface equipment, Petrotek and the MDEQ inspector monitored static annulus pressure or the well annulus for a period of one hour at 10-minute intervals. During the 60-minute test period, the pressure decreased by 3.0 psi, which is a 0.3% change. Since a change of 3% or (29.1 psi) of the test pressure is allowable, this test is within acceptable specifications. A copy of the field measurements of the annular pressure test results recorded on the MDEQ annulus pressure test summary are included as Appendix 2. Appendix 3 presents a copy of the gauge certification. Subsequent to the completion of the test, the annulus tank valve was opened and pressure in the annulus system was lowered by 440 psi and a rise in annulus fluid level of approximately 9.35 gallons was observed. Well No. 1-12 pressures were observed as follows during testing.

TABLE 1

**STATIC ANNULUS PRESSURE TEST MEASUREMENTS
WELL NO. 1-12 (JULY 17, 2018)
EGT, ROMULUS, MICHIGAN**

Time, Minutes	0	10	20	30	40	50	60
Pressure, psi	970	968	968	967	967	967	967

Well No. 2-12

On July 17, 2018 the annulus of Well No. 2-12 was pressured up to 970.0 psi. A calibrated digital pressure gauge (Rosemount 2,000 psi, SN-620406) supplied by EGT was installed on the annulus at the wellhead. After the well was isolated from the surface equipment, Petrotek and the MDEQ inspector monitored static annulus pressure or the well annulus for a period of one hour at 10-minute intervals. During the 60-minute test period, the pressure decreased by 19.0 psi, which is a 2.1% change. Since a change of 3% or (26.8 psi) of the test pressure is allowable, this test is within acceptable specifications. A copy of the field measurements of the annular pressure test results recorded on the MDEQ annulus pressure test summary are included as Appendix 2. Appendix 3 presents a copy of the gauge certification. Subsequent to the completion of the test, the annulus tank valve was opened and pressure in the annulus system was lowered by 444 psi and a rise in annulus fluid level of approximately 9.35 gallons was observed. Well No. 2-12 pressures were observed as follows during testing.

TABLE 2

STATIC ANNULUS PRESSURE TEST MEASUREMENTS
WELL NO. 2-12 (JULY 17, 2018)
EGT, ROMULUS, MICHIGAN

Time, Minutes	0	10	20	30	40	50	60
Pressure, psi	893	888	885	882	879	876	874

Part II: External Mechanical Integrity

Radioactive Tracer Survey - The primary purpose of an RTS Survey is to verify the adequacy of the bottomhole cement surrounding the base of a long string casing. An RTS log was conducted on EGT Well #1-12 in accordance with the approved MIT testing procedures submitted to MDEQ and EPA prior to commencement of field activities and are consistent with USEPA Region 5 guidance documents pertaining to mechanical integrity testing.

General Procedure – RTS

A. Disconnect surface equipment and rig-up pressure control equipment.

B. Run in well with RTS tool and two gamma-ray detectors located below the injector port.

C. Correlate log to existing logs (noting Kelly Bushing). Correlate RTS log to packer and/or natural gamma ray responses. Locate bottom of well if practical or run to at least 100 feet below casing shoe to a depth of not less than approximately 4,200 feet KB if attainable based on wellbore conditions and pull base log a minimum of depth of 3,093 feet KB, or shallower. Run a minimum of one five-minute statistical log in two different lithologies (3,955 and 3,802 feet KB).

D. Start or continue or injection using water at approximately 15 - 50 gpm. Release the first slug in the tubing at a depth above the packer and observe the movement as it passes the lower detector. Record the movement of the slug by repeatedly moving the tool down hole and making a series of overlapping passes as the slug dissipates into the openhole formation.

E. Continue to monitor the slug until there is no indication that it is moving up behind the long string casing.

F. Pull tools into the tubing and release a slug at approximately 3,750 feet KB while injecting. RIH and position the bottom gamma-ray detector at a depth of approximately 4,080 feet KB. Leave the tool stationary and record the log in time drive for 30 minutes while continuing to inject. Run a final base log. At the conclusion of the test, rig down wireline and support equipment.

A copy of the field recorded radioactive tracer survey log in paper form are included as Attachment 1 of this document. Attachment 4 provides digital copies.

Well No. 1-12 - RTS

On July 17, 2018, a radioactive tracer (RTS) was performed on Well #1-12. Depths were correlated to past logs and well configuration, and a gamma-ray base log was run from approximately 4,405 feet to 2,080 feet and five-minute statistical logs were run with the top detector at 3,796 feet and at 3,949 feet. The bottom detector was 5 feet below the top detector at each station. Using the site equipment, fluid was then injected at approximately 32 gallons per minute at 542 psi at surface. A small amount of radioactive material leaked out of the detector just below the packer at about 4,060 feet. This did not cause any difficulty interpreting the log nor did it invalidate the conclusions of the interpreters. The tool was positioned at a depth of 3,100 feet and a slug was released to begin the chase series. A total of 13 passes were run and the slug was observed to enter the injection interval below the casing shoe at 4,080 feet. The tracer materials all moved into the injection interval and there was no indication of any significant movement above the casing shoe or above the top of the injection interval or injection zone.

After the chase pass series, a slug was released at approximately 3,750 feet and the tool was lowered placing the bottom detector at 4,080 feet where a 30-minute time drive was conducted. The slug passed the tool at approximately 340 seconds and no upward movement of the tracer was observed after the slug passed the tool as it was injected down the tubing.

A final base log was then run with a majority of the residual tracer detected from approximately 4,246 to 4,404 feet and the log was approved by the MDEQ field inspector. A paper copy of the log is provided as Attachment 1 and a PDF copy of the log is provided as Attachment 4.

Well No. 1-12 – Static Temperature Survey

A temperature survey was run on July 7, 2018 starting at 9:38 am. The temperature sensor was calibrated by immersing it in buckets of known temperature water at the surface prior to running in hole. The tool stopped recording at 4,250 feet KB. The end of the injection tail pipe in well No. 1-12 is set at 4,055 feet. EPA approved procedures for performing a static temperature survey indicate that the test will be run to 100 feet below the bottom of the tailpipe, therefore this test was sufficient to show mechanical integrity. Analysis of the Static temperature survey log (Attachment 1) shows no indication of fluid injection or movement above the permitted injection interval.

Well No. 2-12 – RTS and Static Temperature Survey

It is noted that a successful APT was performed on Well No. 2-12, but during field operations logging tools were not able to be run to the bottom of the well. As discussed by EGT with EPA and MDEQ, well rehabilitation plans are currently underway which are intended to allow additional mechanical integrity testing to be conducted on the well.

3.0 RESERVOIR TESTING

3.1 Data Collection

Injection-falloff pressure transient data were collected from EGT, Well No. 1-12 at the Romulus, Michigan site July 17-18, 2018. The year 2018 annual reservoir testing was supervised by Rich Schildhouse of Petrotek. Parameters supplied for the Mt. Simon injection interval and the test synopsis are summarized in Attachment 3. Raw data collected by J.O. Well Service are provided as Attachment 4. A J. O. Well Service quartz gauge was utilized to acquire bottomhole pressure data. Downhole gauge calibration information is presented as Appendix 4 of this document.

Test injection began at 16:08 on July 17, 2018. Within approximately one minute, a stable injection rate of approximately 32.1 gallons per minute (gpm) was achieved. At 19:23, a six minute break in injection occurred, while facility personnel performed a valve replacement at the wellhead to allow the test to progress. Injection resumed at 19:29, and immediately stabilized to an average rate of 32.25 gpm over the next 1.5 hours. At approximately 20:84, the tool assembly was set at the test depth of 3,937 feet BGL (3,950' RKB) while injection continued. The offset Well No. 2-12 had been shut-in since August, 2017 and was not operated during the Well No. 1-12 injection or falloff data collection period. Bottomhole injection pressure and temperature were recorded for approximately 8.5 hours prior to start of the falloff test. An average bottomhole injection pressure of 2,300 psig at 3,950 feet RKB (3,937' BGL) at an average flow rate of approximately 31.6 gpm was recorded during the final one-hour injection period prior to falloff testing.

Well No. 1-12 was shut-in at approximately 04:25 on July 18, 2018 by stopping the injection pump while concurrently closing the wellhead valve and pump-house valves. Shut-in was completed within several minutes. Over the final several minutes of flow, rate dropped from 32.5 gpm to 26.7 gpm. Final flow rate was 26.66 gpm (914.1 bpd) and final bottomhole pressure at shut-in was 2,288.61 psig.

After shut-in of Well No. 1-12, pressure falloff in the injection interval was recorded for approximately 8.5 hours after Well No. 1-12 injection was stopped. Pressure had declined to a minimum of approximately 1,796.7 psig by the end of the test. Injection and falloff pressures appear to be of similar magnitude to values measured in previous tests. At the end of the test, static gradient stops made as the tool was pulled from the the well indicated a fluid gradient of approximately 0.423 psi/ft.

3.2 Data Analysis

As summarized in Attachment 3, there are a number of items critical to test analysis. These include data regarding the well and formation, along with data regarding the fluids involved in the testing process. Consistent with past analyses, evaluation of these data was conducted using a value of 133 feet estimated as a probable effective thickness. Other reservoir and fluid parameters were utilized, as reported in the testing conducted during 2015 through 2017, with the exception of rate and time, which are test dependent.

For testing during 2018, rates were determined based on on-site monitoring equipment. A value of 0.798 centipoise was assigned as a representative viscosity of the fluids through which the pressure transients analyzed in this test traveled based on previous analyses.

The following figures have been prepared to examine and analyze the pressure transient data collected from EGT Well No. 1-12 during 2018 reservoir testing. These include: Figures 2 - Cartesian Plot of Pressure, Temperature and Rate vs. Time; Figure 3 - Cartesian Plot of Pressure Falloff; Figure 4 - Radial Flow Derivative/Log-log Plot (Dp vs. Dt); Figure 5 - Radial Flow Semilog/Horner Plot of Pressure Falloff; Figure 6 - Composite Model Test Rate History and Pressure Match; Figure 7 - Composite Model Derivative Match; and Figure 8 - Composite Model Semilog/Horner Match. Attachment 4 includes a digital copy of the falloff pressure data.

Figure 2 is chronological plot of pressure and rate data collected with the bottomhole pressure gauge, and flow data collected with the plant monitoring equipment for the entire duration of the test on Well No. 1-12. Figure 3 is an expanded Cartesian plot of the downhole data during the falloff test. It is evident from examination of the log-log plot (Figure 4) that very early time data are dominated by wellbore storage. Soon after, the slope of both the pressure and pressure derivative decrease during a period that is dominated by changing wellbore storage. No square root pseudo-slopes are apparent in the test. Examination of Figure 4 shows that after a time of approximately 1 hour, the middle time data collected appear to be starting to transition into radial flow in the injection zone.

Assuming a single well in an infinite reservoir, a permeability-thickness of approximately 9,488 md-ft and a P* value of 1,804 psia (3,937' BGL) are derived. At the end of the falloff, pressure had decayed to a value of approximately 1,809 psia. For an effective reservoir thickness of 133 feet, a permeability of 71.3 md is derived. A skin factor of 37.8 is derived in this analysis.

The Semi-log Horner Plot presented as Figure 5 shows the period of possible radial flow consistent with the diagnostic plots. As noted on page 18 of the SPE Well Testing Textbook by Lee (1982), pseudo-producing time tp, was assigned for the Horner analysis by dividing the cumulative injection into the well during the test by the final test flow rate before shut-in. Based on a test period injection into Well No. 1-12 of approximately 574 barrels since the most recent shut-in before the test and a final rate of 26.66 gpm, tp is equal to 15.07 hours. Figures 6, 7 and 8 present analysis of the data generated with a radial flow model. A permeability-thickness of approximately 9,394 md-ft and a P* value of 1,804 psia (3,937' BGL) are derived. At the end of the falloff, pressure had decayed to a value of approximately 1,809 psia (1,796.9 psig). For an effective reservoir thickness of 133 feet, an average permeability of 70.64 md is derived from the simulation. A skin factor of 37.2 is derived in this analysis. This analysis is not atypical as compared with permeability that may exist at some distance from the wellbore and the large skin value is consistent with some historical injectivity declines.

Table 2 presents a comparison of the 2015 through year 2018 falloff analysis results.

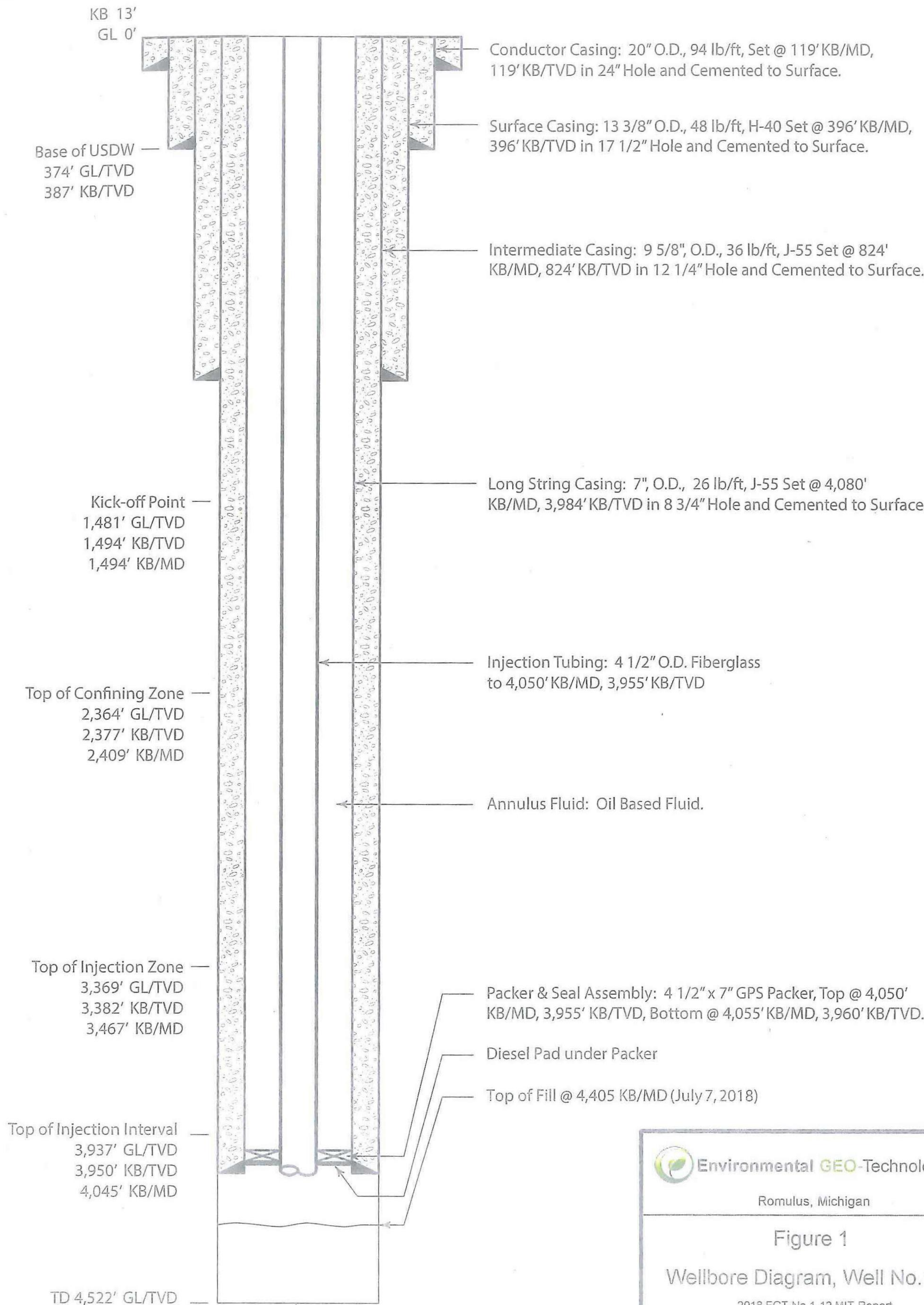
Results are reasonably consistent with values observed locally for the Mt. Simon Formation. In summary, standard industry data collection and analysis procedures were followed with respect to this testing. Appropriate graphs of the data are provided as Figures 5 through 8, which clearly show the relationship of pressure, temperature and time with a simulation analysis.

TABLE 2
HISTORICAL RESERVOIR PRESSURE MEASUREMENTS
EGT, ROMULUS, MICHIGAN - WELL NO. 1-12

Well ID	Date	Gauge Depth (feet KB)	kh (md-ft)	k (md)	Skin	P* (psig)	Final Shut-in Pressure (psig) @ Gauge Depth
1-12	2015	3,950	20,216	152	84	1,773	1,774.9
1-12	2016	3,950	22,225	165	41	1,755	1,761.3
1-12	2017	3,950	14,160	106	44	1,792	1,794.0
1-12	2018	3,950	9,488	71	37	1,804	1,796.7

Site well performance continues to be influenced by skin damage and reduced effective permeability-thickness communicating to the wellbore. If skin increases or near wellbore permeability decreases, well injectivity will tend to decrease. At this time, a majority of the pressure buildup during injection is due to skin damage and near wellbore permeability restrictions. This accounts for a majority of the pressure rise currently observed during injection operations. If it were economically or technically practical to eliminate the skin, the formation could have the capability to accept fluid at higher injection rates with a lower wellhead pressure.

The objective of the annual reservoir testing was to identify significant injectivity changes or new wellbore problems and to confirm that formation properties and pressures have not changed significantly from those expected. These goals were successfully achieved and no significant concerns relevant to continued operation, safety or containment were identified. The current EGT data acquisition and wellhead injection pressure monitoring practices will provide indications of injectivity changes and are sufficient to ensure continued operation at permitted injection pressures. This testing and analysis confirms that the EGT, Well No. 1-12 at Romulus and the disposal reservoir remains suitable for continued disposal use.



Note:
True bottom of Well is 211' South & 754' West of surface location.
Ground Level Elevation 626.6'

From: WSP / Parsons Brinckerhoff, 09/2016 Figure 6

Environmental GEO-Technologies

Romulus, Michigan

Figure 1

Wellbore Diagram, Well No. 1-12

2018 EGT No.1-12 MIT Report

Scale: NTS	Date: August 2018	
2018_EGT_No1-12_Wellbore.ai	By: KRS	Checked: RHP

Petrotek
5935 South Zang Street, Suite 200
Littleton, Colorado 80127 USA
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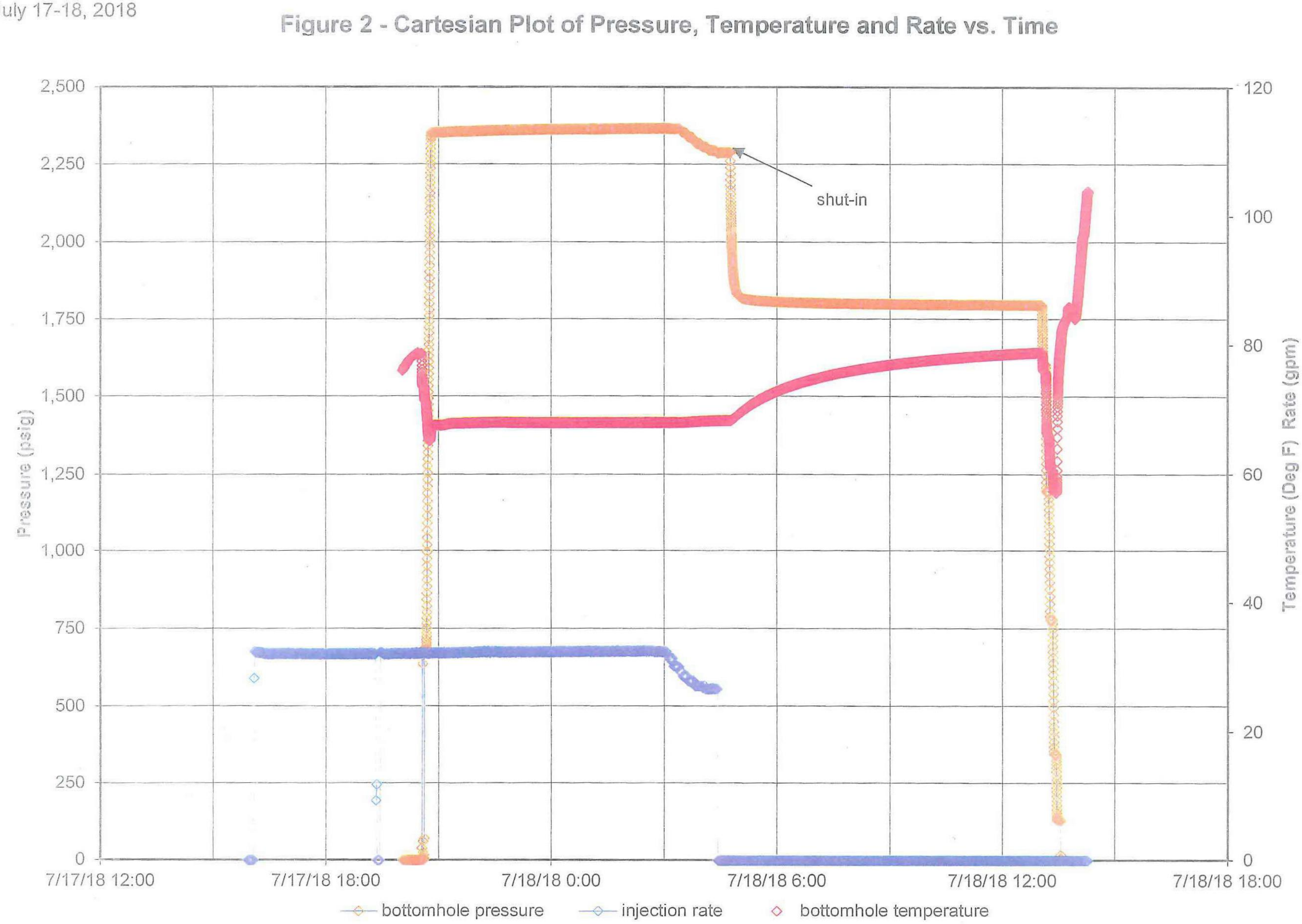
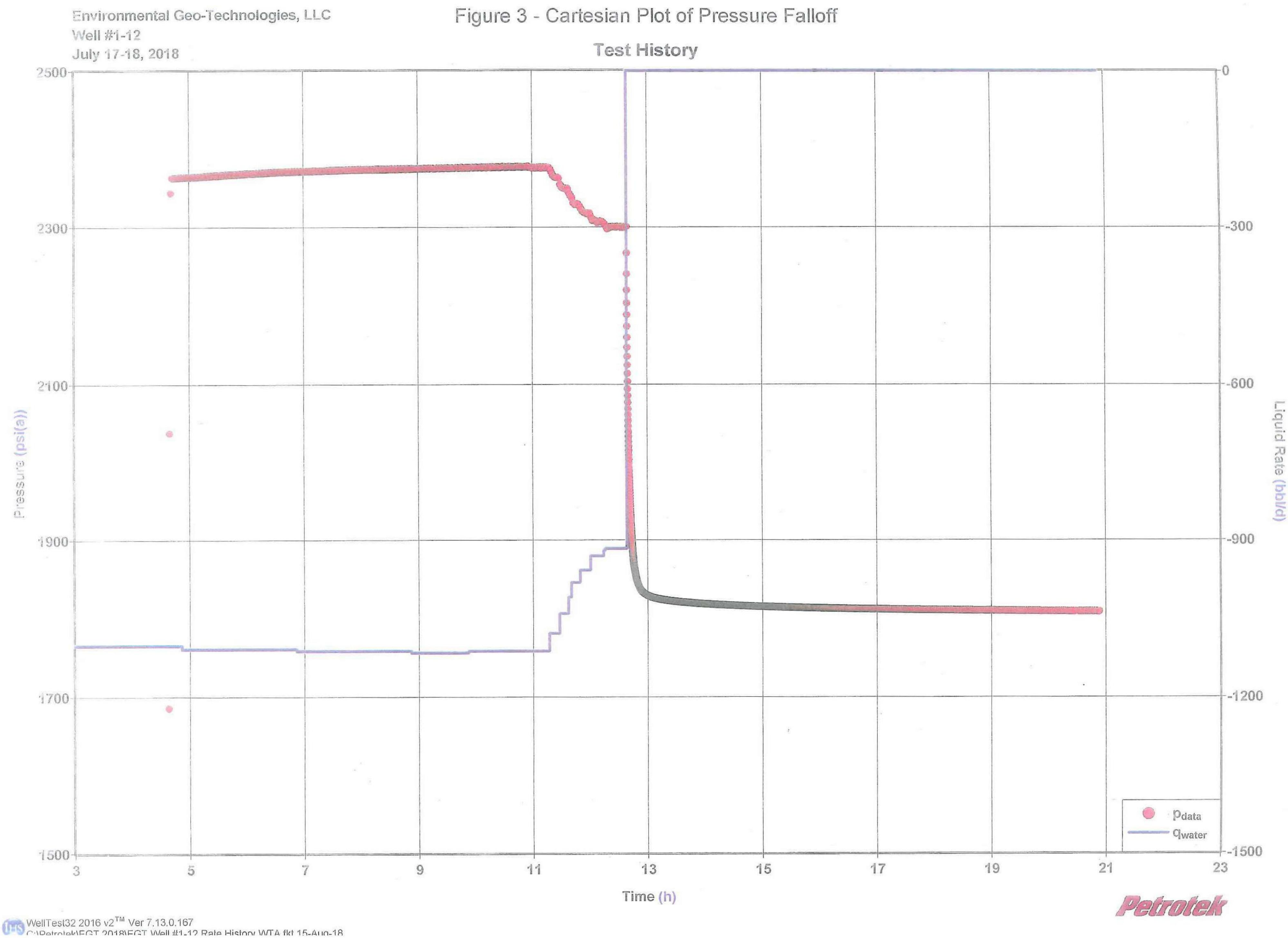


Figure 2 - Cartesian Plot of Pressure, Temperature and Rate vs. Time
Pressure (psig)
Temperature (Deg F) Rate (gpm)
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
120
100
80
60
40
20
0
shut-in
7/17/18 12:00
7/17/18 18:00
7/18/18 0:00
7/18/18 6:00
7/18/18 12:00
7/18/18 18:00
bottomhole pressure
injection rate
bottomhole temperature

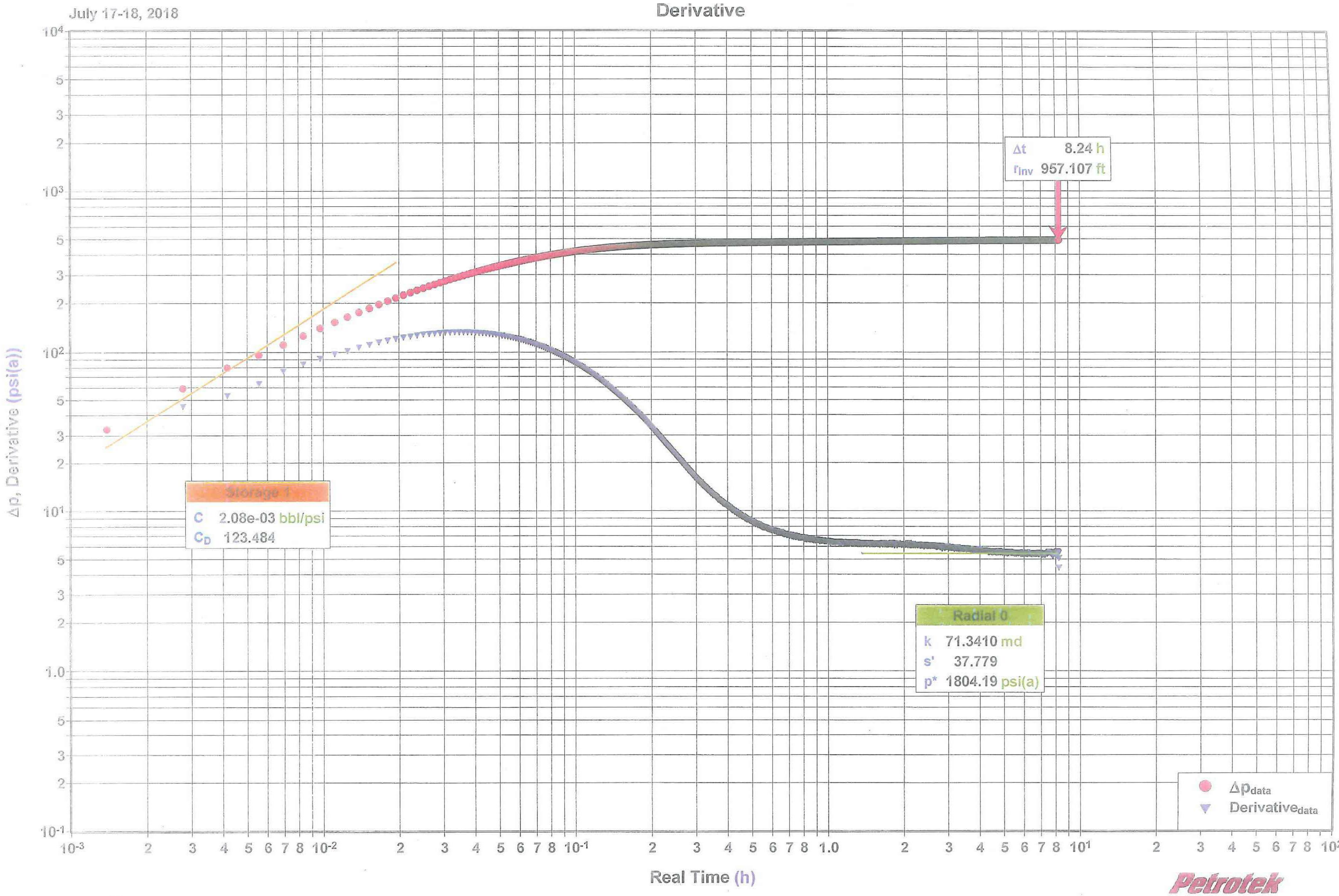
Petrotek



Environmental Geo-Technologies, LLC
Well #1-12
July 17-18, 2018
Figure 3 - Cartesian Plot of Pressure Falloff
Test History
Pressure (psi(a))
Liquid Rate (bbl/d)
Time (h)
2500
2300
2100
1900
1700
1500
0
-300
-600
-900
-1200
-1500
3
5
7
9
11
13
15
17
19
21
23
p_{data}
q_{water}
Petrotek
WellTest32 2016 v2™ Ver 7.13.0.167
C:\Petrotek\EGT 2018\EGT Well #1-12 Rate History WTA.fkt 15-Aug-18

Environmental Geo-Technologies, LLC
Well #1-12
July 17-18, 2018

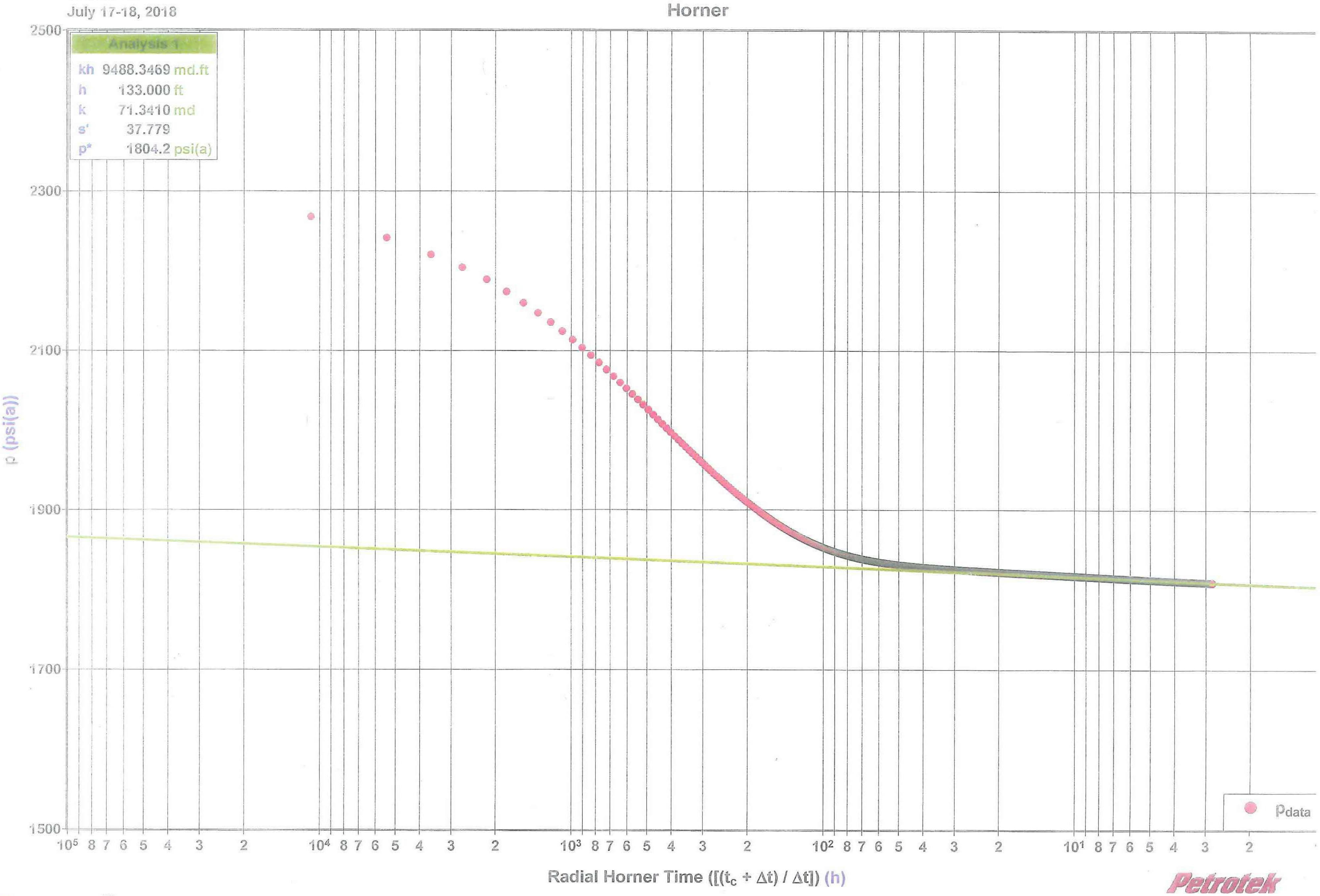
Figure 4 - Radial Flow Derivative/Log-log Plot (Dp vs. Dt)



WellTest32 2016 v2™ Ver 7.13.0.167
C:\Petrotek\EGT 2018\EGT Well #1-12 Rate History WTA.fkt 15-Aug-18

Figure 5 - Radial Flow Semilog Horner Plot of Pressure Falloff

Environmental Geo-Technologies, LLC
Well #1-12
July 17-18, 2018



WellTest32 2016 v2™ Ver 7.13.0.167
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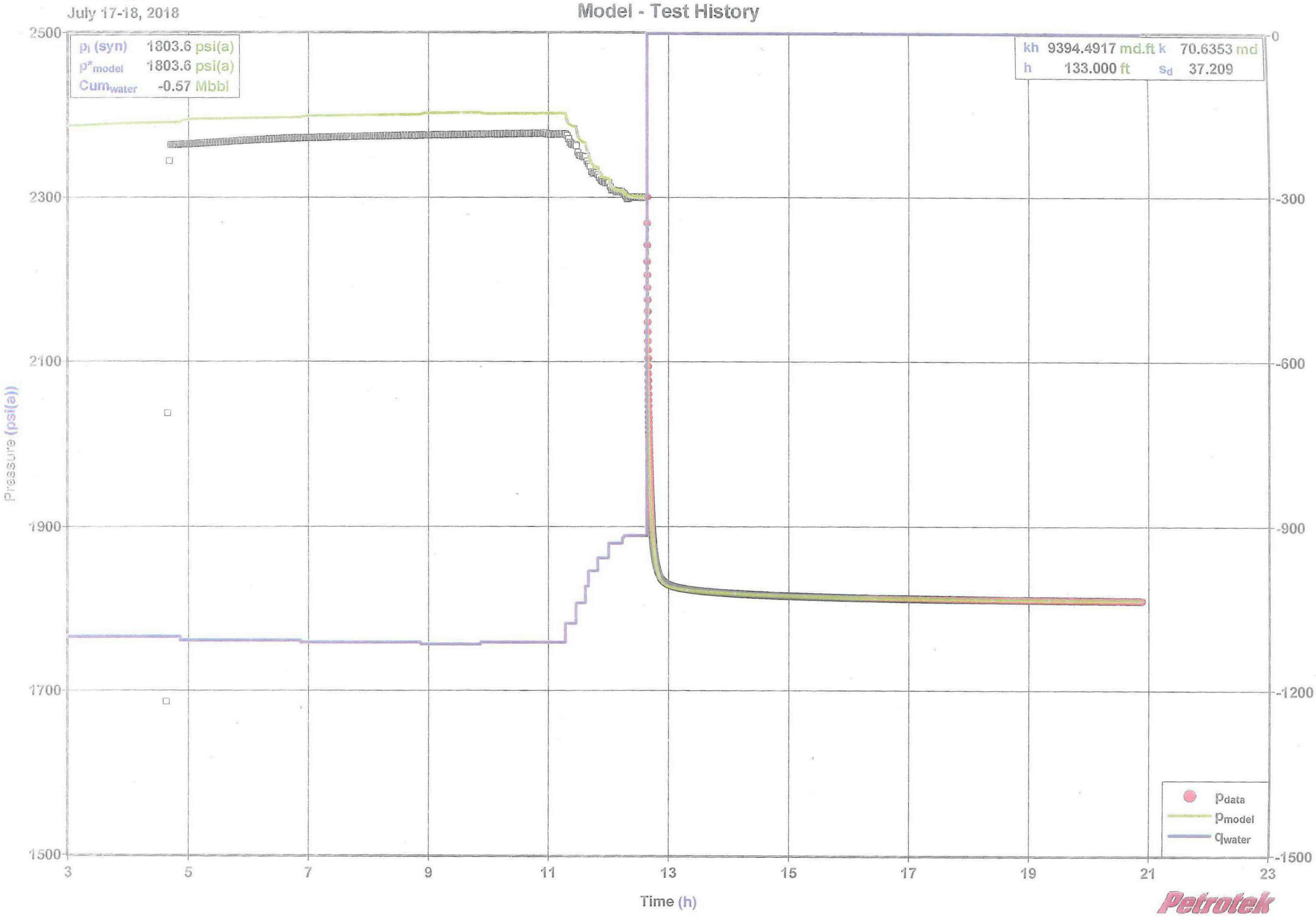
Environmental Geo-Technologies, LLC
Well #1-12
July 17-18, 2018

Figure 6 - Homogeneous Model Test Rate History and Pressure Match



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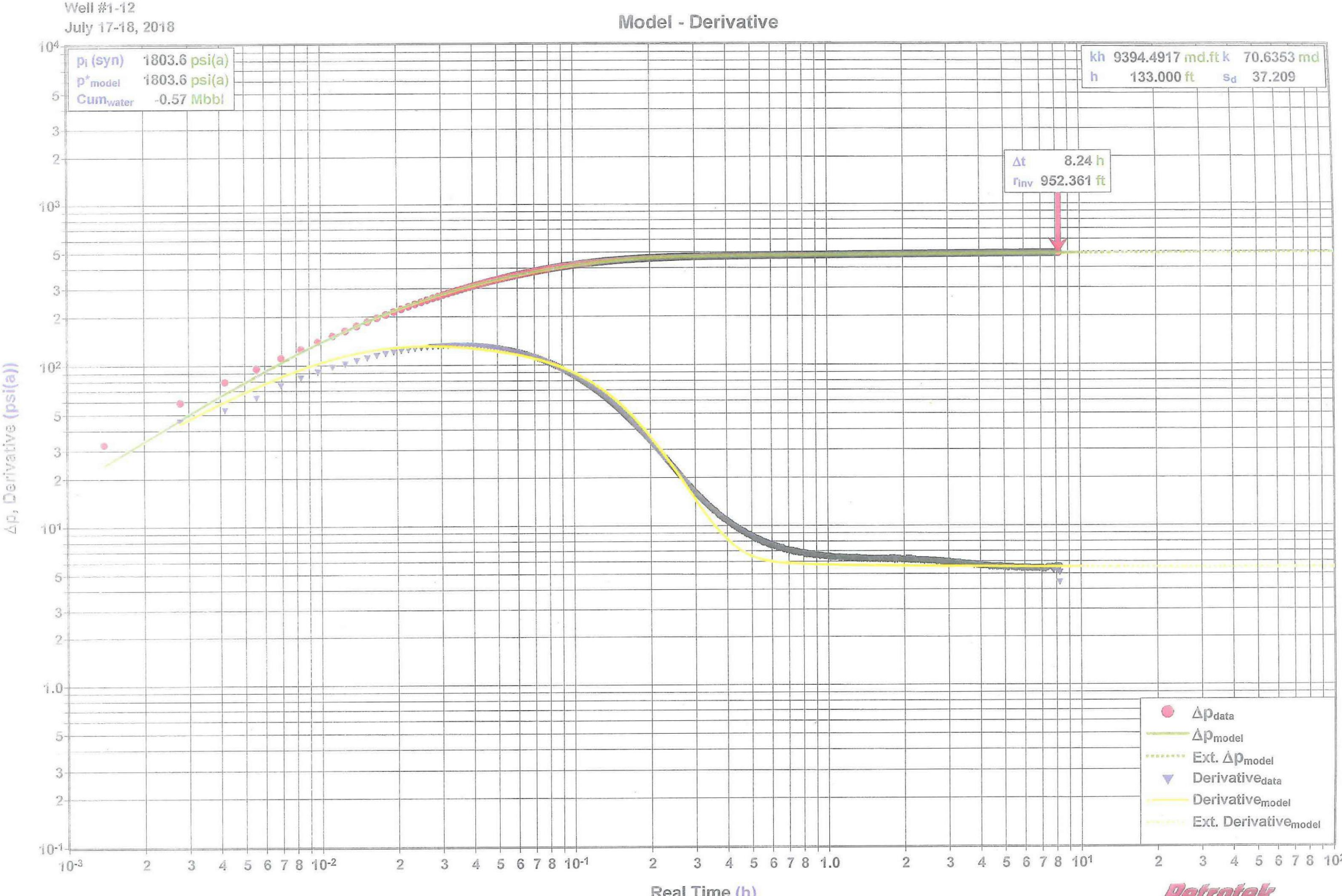
Environmental Geo-Technologies, LLC
Well #1-12
July 17-18, 2018

Figure 7 - Homogeneous Model - Derivative Match



Petrotek

WellTest32 2016 v2™ Ver 7.13.0.167
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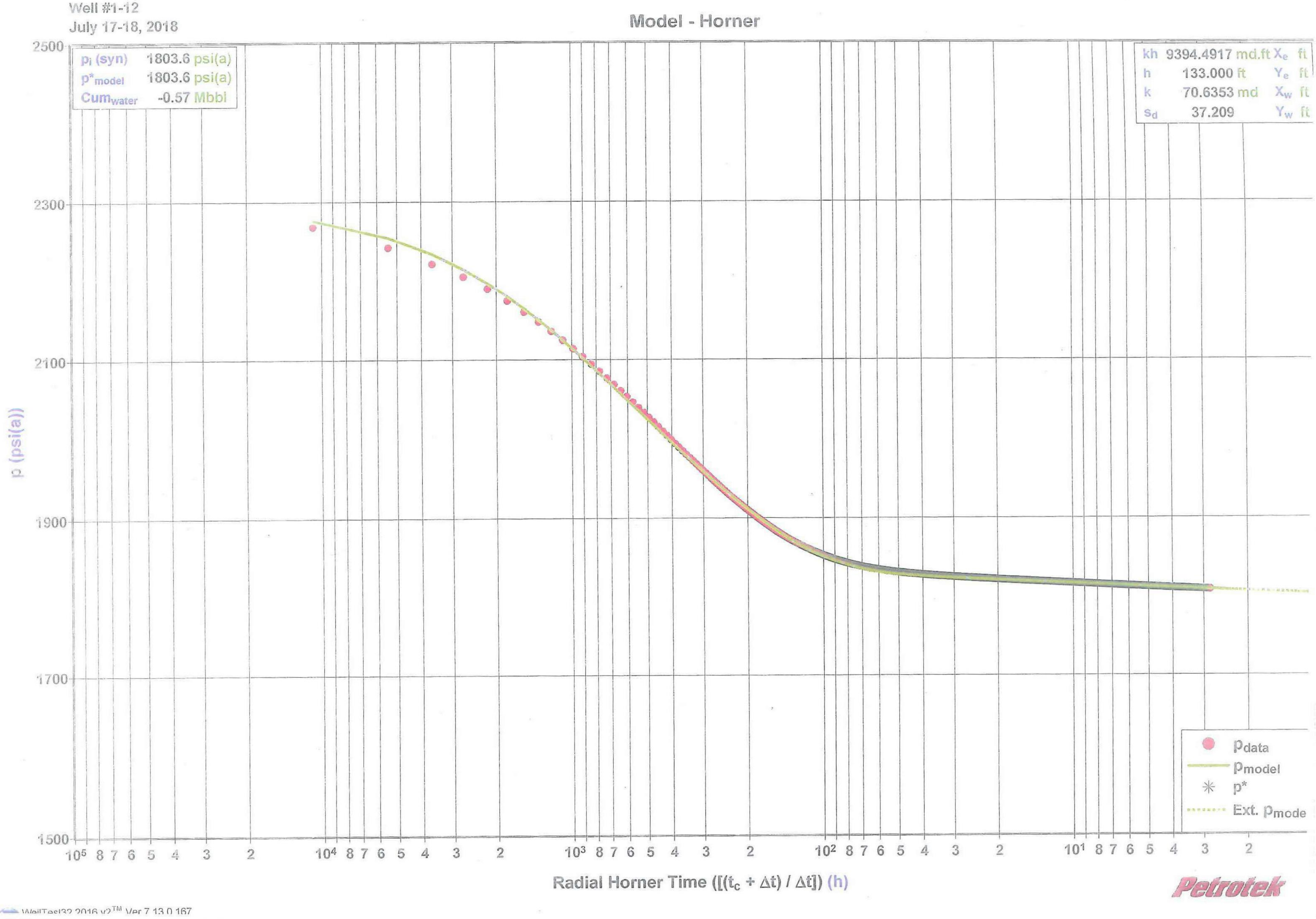
Environmental Geo-Technologies, LLC
Well #1-12
July 17-18, 2018

Figure 8 - Homogeneous Model – Semilog Horner Match



Environmental GEO-Technologies

SENT VIA EMAIL and US MAIL

June 14, 2018

Mr. Stephen Jann
US EPA, Region 5
UIC Section, (WU-16J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590
jann.stephen@epa.gov

Mr. Ray Vugrinovich
Michigan Department of Environmental Quality
Constitution Hall
525 West Allegan Street, South Tower, 1st Floor
Lansing, MI 48933
vugrinovichr@michigan.gov

RE: Environmental Geo-Technologies, LLC – Romulus, Michigan
2018 MIT Notification Well #1-12 and #2-12
(UIC Permits: MI-163-1W-C010, MI-63-1W-C011)

Dear Mr. Jann and Mr. Vugrinovich:

Please accept this letter as notice that Environmental Geo-Technologies, LLC ("EGT") will be conducting annual mechanical integrity testing at the Romulus, Michigan Facility during the week of July 16, 2018. Included with this letter are proposed procedures for conducting the proposed MIT activities. They are based on applicable Region 5 input and procedures that have been approved and successfully utilized in past years at the site. EGT will be utilizing Petrotek Corporation to complete this testing and requests that EPA and MDEQ accept additional communications directly from Petrotek regarding logistics for this MIT project as may be needed to complete the project. All communication with our technical consultant regarding this matter should be copied to my attention.

EGT has tentatively scheduled Petrotek to complete the required MIT activities during the period of July 16 - 20, 2018 in order to comply with annual deadlines, but the schedule may be altered based on vendor and inspector availability. Injection falloff tests, annulus pressure tests, radioactive tracer logs and static temperature logs are scheduled to be performed on each of the two wells per the applicable annual deadlines. This suite of testing is intended to satisfy all mechanical integrity requirements needed for maintaining compliance for this year.

At your convenience, please advise us regarding EPA and MDEQ plans for regulatory witnessing of the 2018 MIT activities so that we can coordinate with the UIC field inspectors regarding availability. Please do not hesitate to contact me at 734-946-1000 or our technical consultants Ken Cooper or Richard Schildhouse at Petrotek (303) 290-9414 if you have any questions regarding this notice.

Sincerely,

John Frost

Environmental Geo-Technologies, LLC
John Frost
General Manager

cc: Zachary Stevison - USEPA Region 5
Lisa Perenchio - USEPA Region 5
Lilly Simmons - USEPA Region 5
Stafford Dusenbury - MDEQ
Richard Schildhouse - Petrotek
Ken Cooper - Petrotek

2018 ANNUAL MIT PROCEDURES
ENVIRONMENTAL GEO-TECHNOLOGIES, LLC - ROMULUS, MICHIGAN FACILITY

1. Annulus Pressure Tests – Well Nos. 1-12 and 2-12

   A. Ensure that well to be tested has been shut-in for a minimum of 36 hours. Record initial annulus tank level and pressure. Record tubing injection pressure.

   B. Install certified test pressure gauge on annulus valve/test port.

   C. Pressurize well annulus and annulus tank to +/-875 to +/-925 psi with nitrogen and isolate annulus. To ensure personnel safety and environmental protection, do not exceed normal operating pressure range without verification of annulus tank relief valve and other surface equipment ratings/conditions.

   D. Allow annulus pressure to stabilize. The annulus may need to be pressurized and bled-off several times to ensure an absence of gas. Minimum specified annulus pressure listed in 1.A must be maintained throughout one-hour test consistent with prior testing.

   E. Isolate annulus pressure tank and nitrogen supply from wellhead and test gauge.

   F. Monitor and record annulus pressure for one (1) hour at a minimum of ten (10) minute increments or as otherwise instructed by regulatory inspector with well shut-in. Pressure may not fluctuate more than 3% during the one-hour test.

   G. Open valves to allow annulus tank to communicate to wellhead. Note annulus tank level and pressure. If needed, bleed annulus to normal operating pressure. Note final annulus level and pressure to verify communication with well annulus. Conduct any annual alarm testing requested by agency representative.

   H. Return monitoring and annulus system to service and return well to operator control.

   I. Provide copy of test gauge certification (>12 months old) to inspector on-site. Provide copy of field test records and certified annulus pressure gauge calibration data to agency in written report.

2. Static Temperature Log – Well Nos. 1-12 and 2-12

   A. Conduct safety briefings, verify wellhead conditions and rig-up lubricator on test well.

   B. Verify that well to be tested has been shut in for a minimum of 36 hours. Conduct bucket test verification of temperature logging tool operations at ambient surface temperature and in ice water by comparison of tool temperature output to independant thermometer.

C. Rig-up pressure control equipment and temperature tool with gamma-ray and/or collar locator.

D. Run tool downhole at not more than an average speed of not greater than 30 feet per minute. Run log to at least 100 foot below bottom of tail pipe to a minimum depth of approximately 4,646 feet KB in Well #1-12 and 4,550 feet KB in Well #2-12 as practical based on wellbore conditions. Correlate log to existing logs using natural gamma-ray responses, casing collar locator and/or known packer setting depth

E. Compare log to previous log(s) run in well of interest. Present temperature data on 1" and 5" per 100' scales.

F. If anomalies relevant to identifying potential upward flow out of the injection zone are indicated, run repeat log section, and/or run additional temperature log at subsequent shut-in time per guidance and/or perform additional logging near depth of anomaly.

G. Rig down equipment and return to standby or prepare for additional testing.

H. Submit both paper and electronic records of log data with analysis report.

3. **Radioactive Tracer Survey (RTS or RAT Logging) – Well Nos. 1-12 and 2-12**

A. Conduct safety briefings, verify wellhead conditions and rig-up lubricator on test well.

B. Run in well with RTS tool with collar locator and locate gamma-ray detector below injector port on tool. Iodine 131 to be used as tracer.

C. Correlate to existing logs (noting Kelly Bushing). Correlate RTS log to packer and/or natural gamma ray responses. Locate bottom of well if practical or run to at least 100 feet below casing shoe to a depth of not less than approximately 4,200 feet KB if attainable based on wellbore conditions and pull base log a minimum of depth of 3,093 feet KB, or shallower.

D. Run a minimum of one five-minute statistical log in two different lithologies. (approximate depths for bottom detector +/- 20 feet: Well #1-12 – 3,955 and 3,802 feet KB, Well #2-12 – 3,855 and 3,800 feet KB).

E. Start or continue injection at a rate that the operator is able to track the slug movement down-hole based on field supervisor observation and judgement of field conditions. Target rate likely to be 15 to 50 gpm.

F. Release the first slug in the tubing at a depth above the packer and observe the movement as it passes the lower detector. (approximate target depths for first slug release with ejector port +/- 20 feet: Well #1-12 – 3,100 feet KB, Well #2-12

– 3,750 feet KB). Move tool downhole and after catching the slug in the tubing at least twice, attempt to position the detector near the injection tubing tail. Once the slug is detected at the tubing tail, record the movement of the slug by repeatedly moving the tool down-hole and making a series of up-hole, overlapping passes as the slug dissipates into the injection formation. Five to eight passes as determined by the field supervisor may be necessary to complete the chase series. Note the top depth reached by the slug during the testing.

G. Continue to monitor the slug until it is dissipating into the injection zone. If a split occurs, monitor the upward moving slug until it is dissipating.

H. After the chase series is complete, pull tools into the tubing and release a slug at approximately 3,750 feet KB while injecting. RIH and position the bottom gamma-ray detector at a depth of approximately 4,080 feet KB (+/- 5 feet) in Well #1-12 and a depth of approximately 3,977 feet KB (+/- 5 feet) in Well #2-12 or as required by well conditions. Leave the tool stationary and record the log in time drive for a minimum of 30 minutes while continuing to inject.

I. After the time drive log is complete, run a final base log from bottom up over approximately the same interval as initial base log was run. Exceeding any minimum target standard identified in this procedure will be acceptable.

J. At the conclusion of the test, rig-down wireline RTS tools and support equipment and return to standby or prepare for additional testing.

K. Submit both paper and electronic records of log data with analysis report.

4. **Ambient Reservoir Pressure Monitoring, (Injection Falloff test) – Well Nos. 1-12 and 2-12**

A. Inject into test well for a minimum of 12 hours prior to planned falloff. Attempt to maintain an approximately stabilized rate (+/-25%) at approximately 15 to 40 gpm as practical.

B. Initiate shut-in or approximately stabilized rate injection rate into offset (non-test) well a minimum of 4 hours prior to planned shut-in for test well falloff.

C. Record rate and pressure data for both wells using existing monitoring equipment.

D. Conduct safety briefings, verify stabilized rate into active well(s) and rig-up lubricator on test well.

E. Run wireline conveyed pressure transducer to test depth (approximately 3,950' KB if practical) a minimum of 2 hours prior to planned shut-in. Collect data at minimum of 6-second intervals for a minimum of 5-minutes prior to shut-in and during fall-off test period.

F. Shut-in injection pump as quickly as practical and fully close all valves to isolate test well from injecting well (if active).

G. Continue monitoring bottomhole pressures for a minimum of 8 hours. After testing is complete, conduct four static gradient survey stops as the tool is pulled from well. Also record final gradient at wellhead in lubricator. Record static pressure and temperature data for a minimum of three (3) minutes at each gradient stop.

H. Submit both paper and electronic records of bottomhole pressure data along with downhole pressure transducer calibration information with analysis report.

BACKGROUND INFORMATION FOR ANALYSIS OF PRESSURE FALL-OFF TEST

FACILITY NAME		OPERATOR	
Romulus Facility		Environmental Geo-Technologies, LLC	
WELL NAME		USEPA PERMIT NUMBER	STATE PERMIT NUMBER
Well #1-12		MI-163-1W-C010	M-452
TEST START DATE	TEST END DATE		
July 17, 2018	July 19, 2018		

GEOLOGICAL DATA

POROSITY, decimal	NET PERMEABLE THICKNESS, ft.	VISCOSITY, cp.	COMPRESSIBILITY, per psi total
0.11	133 ft	0.798 cP	7.7136×10^{-6} (1/psi)

WELL AND OPERATION DATA

LONGSTRING CASING DIAMETER, ins	FINAL PRETEST FLOW RATE, gpm	INJECTATE TEMPERATURE, deg.F	KB ELEVATION, ft
7.000	26.66 gpm	76 deg. F.	626.6
OPEN HOLE DIAMTER, ins	PRETEST FLOW TIME, hrs. SEE BELOW	INJECTATE SPECIFIC GRAVITY	TEST DEPTH FOR COMPARISON, ft
8.75	12 hrs	1.0	3,950 ft
GAUGE DEPTH, ft		CUMULATIVE VOLUME INJECTED SINCE LAST PRESSURE EQUALIZATION,	
3,950 ft		557 bbls	

TEST DATA

GAUGE CALIBRATION DATE			
Feb 24, 2018			
FLOW RATE, gpm	PRESSURE AT BEGINNING OF FALL-OFF, p	PRESSURE AT END OF FALL-OFF, ps	TO SUPPORT FULL COLUMN, psi
26.66 gpm	2,288.6 psi	1,796.7 psi	1,710.35 psi
TEST LENGTH, hrs.	INITIAL GRADIENT, psi/ft.	FINAL GRADIENT, psi/ft.	FINAL FLUID LEVEL, ft.
8.5 hrs	0.579 psi/ft	0.454 psi/ft	0 feet, BGL

REMEMBER

"Pre-test flow time" is the time since the reservoir was last in equilibrium. This may be the time since the well was last shut-in but only if the well was shut-in long enough for the pressure in the reservoir to approach equilibrium pressure.

1. Injection of normal injectate at normal rate is preferred.
2. Please compare data in your records to that in the cells above. If there is a difference, be sure the correct information is noted. Please fill in the information in the other cells.
3. Please submit an up-to-date well schematic
4. Data should be collected at the maximum rate for at least the first five minutes; between five and thirty minutes at no less than one reading every 30 seconds. After thirty minutes, the operator can reduce frequency as required.
5. Submit a copy of the calibration certificate for the gauge used for pressure measurements.